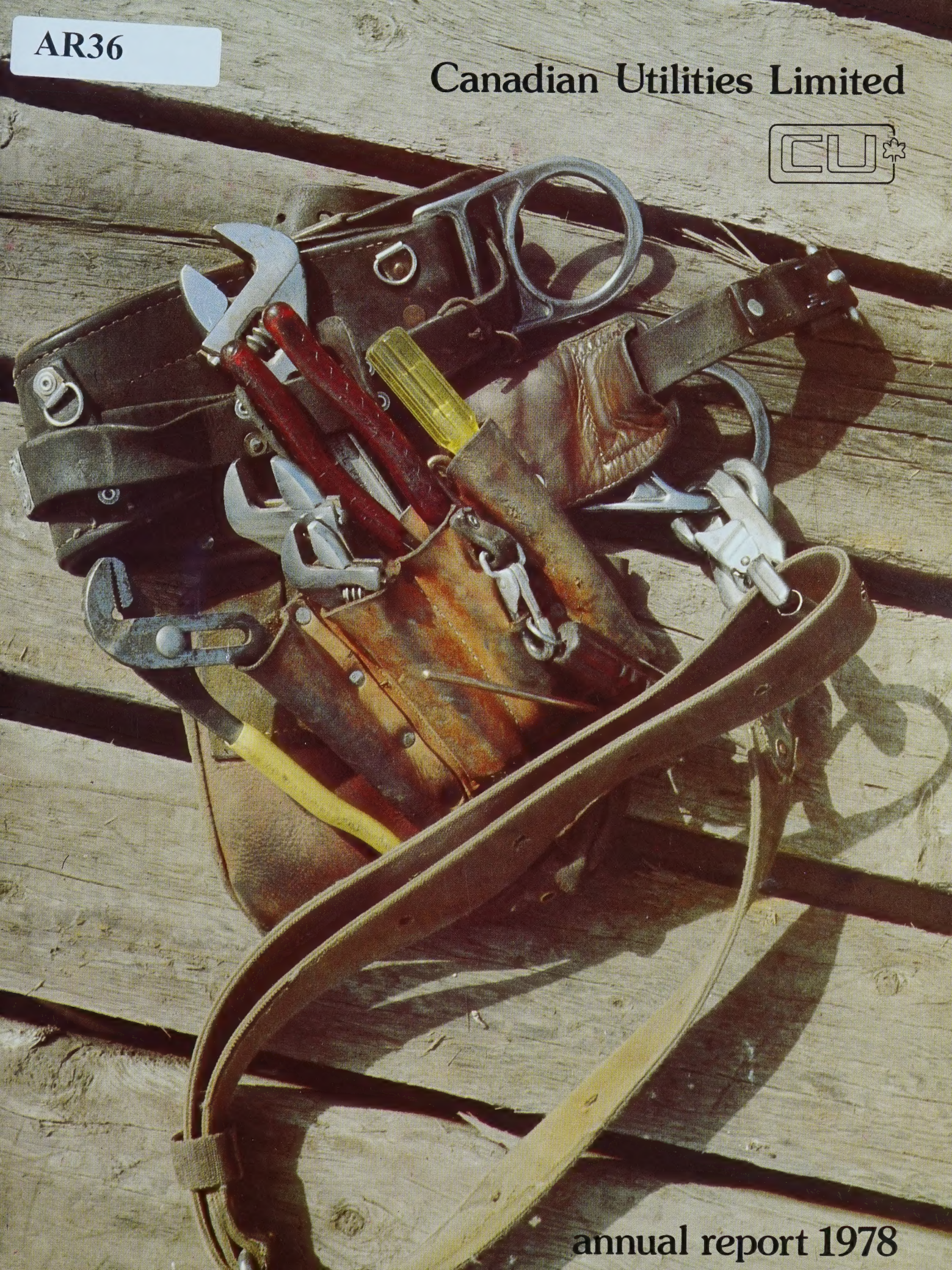


AR36

Canadian Utilities Limited

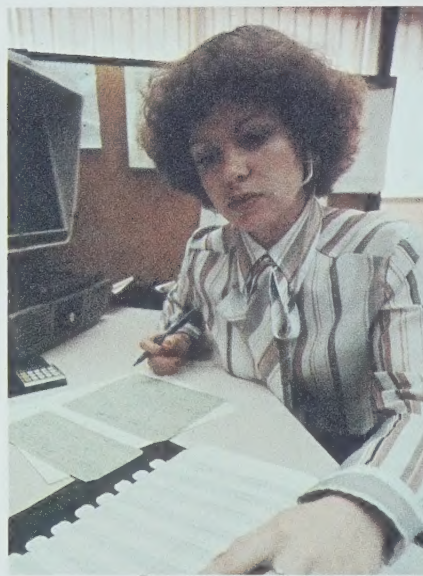


annual report 1978

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The pictures in this report provide what we believe are interesting studies of some of the 3,500 employees and the variety of materials and equipment that characterize the company. The photographer was Alex Macdonald of Edmonton. On the cover, an electrical lineman's belt symbolizes the human and technical resources which combine to bring our services to the public.



*An operator checks the furnace interior at the Battle River #4 Generating Station. One hundred tons per hour of pulverized coal are consumed in the furnace in which temperatures exceed 1200°C.*

# HIGHLIGHTS

	1978	1977	Increase
<b>Revenues (thousands)</b>			
Natural gas	\$431,726	\$318,707	\$113,019
Electric	114,714	93,934	20,780
Other	7,736	2,732	5,004
<b>Total</b>	<b>554,176</b>	<b>415,373</b>	<b>138,803</b>
<b>Net earnings from operations (thousands)</b>	<b>45,045</b>	<b>35,168</b>	<b>9,877</b>
<b>Fully diluted earnings per common share*</b>	<b>1.97</b>	<b>1.61</b>	<b>.36</b>
<b>Dividends paid per share</b>			
Annual	.91 1/4	.85 1/4	.06
Fourth quarter	.24 1/2	.22 1/4	.02 1/4
<b>Market value per share</b>			
High	18	15 1/2	2 1/2
Low	14 1/8	12 5/8	1 1/2
Close	16 1/8	15 1/2	5/8
<b>Capital expenditures (thousands)</b>	<b>108,018</b>	<b>97,527</b>	<b>10,491</b>
<b>Customers at year-end</b>			
Natural gas	457,403	428,438	28,965
Electric	112,490	106,855	5,635

\*Does not include a non-recurring loss of \$1,592,000 or \$.09 per share in 1977.



# TO THE SHAREHOLDERS

We are pleased to report that 1978 was a satisfactory year for Canadian Utilities Limited, particularly in terms of the company's success in serving its utility customers effectively while keeping cost increases to a minimum and maintaining its financial strength during a period of continuous expansion.

The return to near normal weather conditions and the accurate forecasting of utility revenue requirements resulted in a return on invested capital for each of the utility subsidiaries which was close to that established by the Public Utilities Board of Alberta. The difficult task of producing reliable forecasts of costs and revenue requirements is especially important in regulated utilities and the good results of the past year are testimony to the abilities of the employees involved in the planning process.

Net earnings per common share from operations increased by 22 per cent to \$1.97 compared to \$1.61 a year earlier. Total net earnings from operations attributable to common shares were \$35.6 million compared to \$27.7 million in 1977.

The dividend rate on the common shares was raised in the fourth quarter of 1978 to 24½¢, up 10 per cent from the previous quarterly payment of 22¼¢. This was the eighth increase in the last seven years. In that period the dividends paid have equalled about one-half of the earnings attributable to common shares.

The improvement in earnings coincides with a substantial increase in the need for funds to finance an ongoing program of new construction to meet the future energy demands of our utility customers. The money for such expenditures on new plant must come from a balance of funds internally generated and those provided by external financing. Capital expenditures of \$108 million in 1978

(\$98 million in 1977) are expected to exceed \$200 million each year over the next five years. The greater portion of this program is for construction of additional coal-fired electric generation capacity. Battle River Unit #5 is scheduled for completion in 1981, and the Sheerness station is expected to be in operation in the mid-1980's. Following public hearings, the Alberta Energy Resources Conservation Board announced in January, 1979 that it would recommend to the provincial cabinet the construction of the Sheerness station, with the first unit to be commissioned in 1985 and the second in 1986.

External financing in 1978 consisted of two issues to Canadian investors. CU Ethane Limited, a subsidiary company, placed \$20 million of term preferred shares privately and the company received \$19.3 million in proceeds from the issue of 1.35 million common shares. A history of obtaining reasonable and timely regulatory treatment has helped the company ensure a receptive market for the issue of new common shares at values that, after absorbing the costs of the issue, are somewhat above the net book value of existing shares.

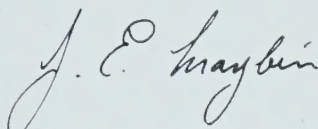
A welcome let-up in the tempo of activity related to new rate applications has been evident recently with only one of the utility operating subsidiaries submitting a full rate application since the beginning of 1978. Every effort is being made to minimize cost increases and, aside from any changes made necessary by increases in the field price of natural gas which is set by federal-provincial agreement, it is hoped that rate adjustments can be avoided throughout 1979.

The non-utility operations of the company have expanded significantly in the year as a result of the completion and successful start-up of the ethane extraction plant, jointly owned by CU Ethane Limited and Dome Petroleum Limited. We must note, however, that Other Operations still represent less than four per cent of earnings attributable to common shares.

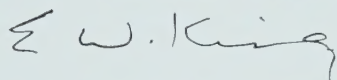
Effective January 1, 1979, A. M. Anderson was appointed secretary of the company. He succeeded W. A. Sullivan who retired after 42 years of distinguished service.

The company now provides employment for 3,500 persons. One of its objectives is to provide satisfying career opportunities for men and women in all areas of the company's operations. Our employees' personal dedication and ability to meet the challenges of the past have been major factors in our record of progress and provide us with a sound basis for optimism about the future.

On behalf of the Board of Directors



J. E. Maybin, Chairman and  
Chief Executive Officer



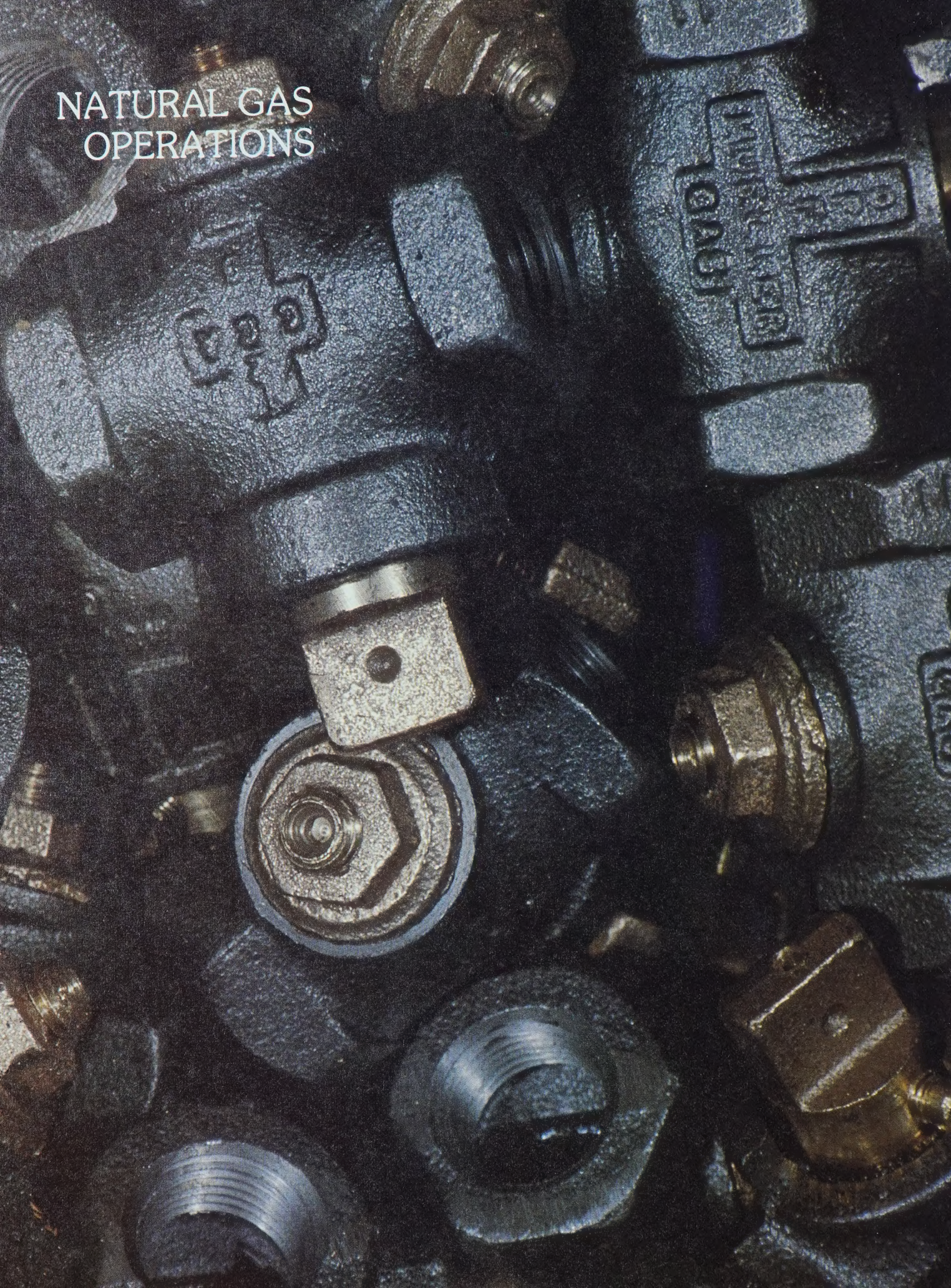
E. W. King, President

February 1, 1979.

*A close-up of flange bolts joining two sections of a natural gas pipe assembly.*

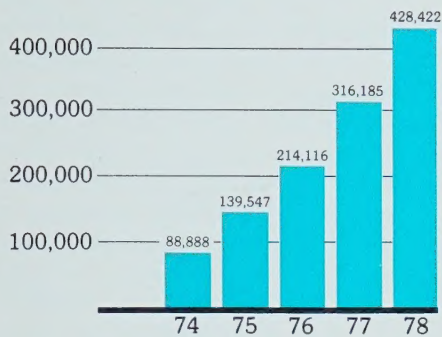


# NATURAL GAS OPERATIONS



## Natural Gas Revenues

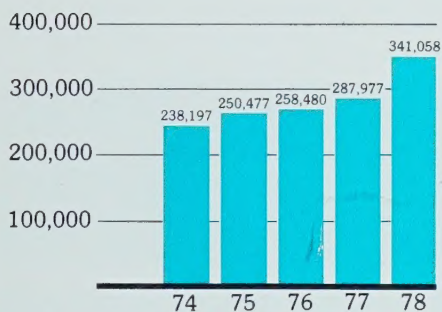
(Thousands of dollars)



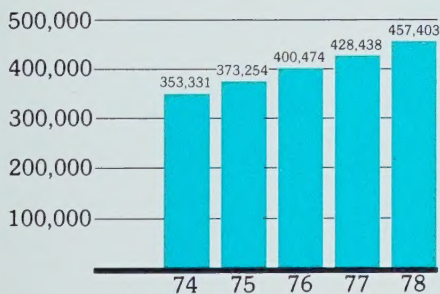
In the chart above natural gas revenues include only those resulting directly from the sale of natural gas. Natural gas revenues per financial statement include other miscellaneous operating revenues.

## Natural Gas Sales

(Millions of cubic feet)

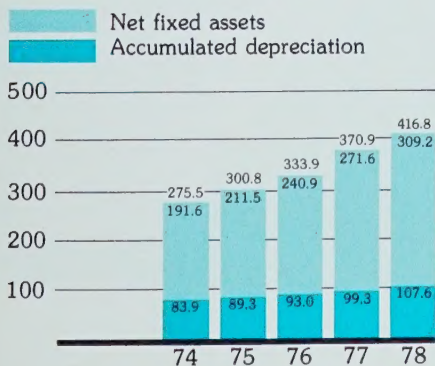


## Natural Gas Customers



## Net Fixed Assets

(Millions of dollars)



A bin of natural gas shut-off valves.

Canadian Utilities' gas operations are carried out by two main subsidiaries: Canadian Western Natural Gas Company Limited, supplying southern Alberta, including Calgary and Lethbridge; and Northwestern Utilities Limited, serving north-central Alberta, including Edmonton, Red Deer, Fort McMurray and Grande Prairie. A subsidiary of Northwestern, Northland Utilities (B.C.) Limited, supplies Dawson Creek and district in northeastern British Columbia.

System growth and a return to more normal weather conditions in Alberta combined to raise total 1978 gas sales 18 per cent to 341 billion cubic feet from 288 billion cubic feet in 1977. The earlier year had been milder than usual in much of the province. In terms of degree days, a measure of space heating requirements, Northwestern Utilities experienced a near-normal year in 1978, while Canadian Western recorded seven per cent colder than normal weather.

## Markets Grow

Growth in both Canadian Western's and Northwestern Utilities' service areas is best exemplified by the two largest cities of Calgary and Edmonton where, in each case, the value of building permits issued during 1978 exceeded the billion dollar mark for the first time. A record 28,965 new gas customers were added throughout the companies' systems, bringing the number served to 457,403.

Capital expenditures for gas operations in 1978 were \$48.2 million compared to \$38.8 million in 1977. Outlays were mainly for expansion of transmission and distribution facilities.

The growth in sales volume was partially offset by a reduction in usage per customer in the residential and commercial markets, the result of conservation efforts on the part of consumers together with an increasing proportion of row housing and mobile homes which tend to use less gas than traditional residences. The gas companies continue to conduct information programs promoting the safe and efficient use of natural gas.

	Billions of Cubic Feet	Per Cent of Total
Industrial	182.8	53.6
Residential	77.1	22.6
Commercial	74.1	21.7
Other	7.1	2.1
Total	341.1	100.0

New maximum daily demands were met by both the major gas utilities during the year: 1,147 million cubic feet for Northwestern Utilities; and 729 million cubic feet for Canadian Western.

Natural gas revenues were \$431.8 million, up \$113.1 million from the previous year. Operating expenses, which include the costs of natural gas, operations, maintenance, depreciation and taxes on revenue were \$396.6 million compared with \$289.3 million in 1977. The highest expense item, accounting for nearly 80 per cent of operating expenses, was natural gas costs, which in 1978 were \$315.5 million, up \$94.4 million from the previous year. Gas costs were net of \$95.3 million in rebates received from the Alberta government under the Natural Gas Price Protection Plan. In 1977, rebates totalled \$62.5 million.

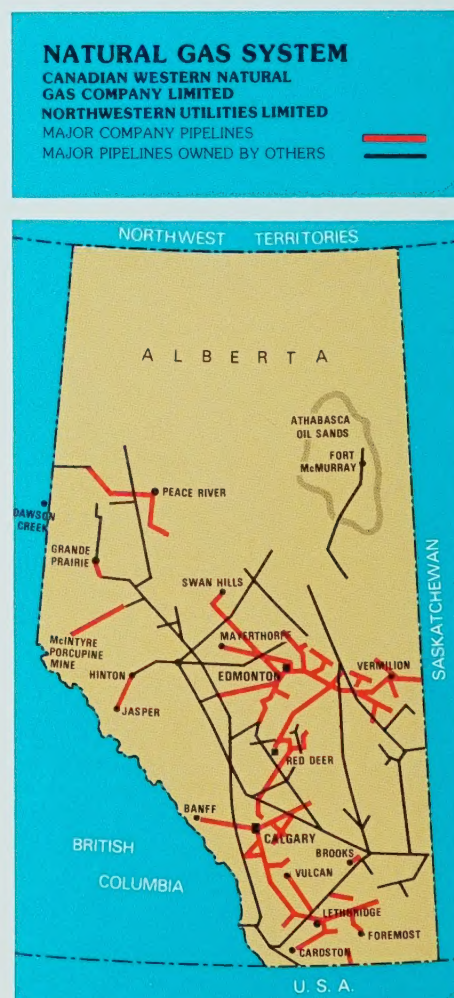
## Gas Operations Earnings Contribution

	1978	1977	1976	1975	1974	1973	Annual Growth Rate 1973-1978 (per cent)
	(Millions of dollars)						
Natural gas revenues	<b>431.8</b>	318.7	216.5	141.8	91.2	82.0	39.4
Operating expenses							
Natural gas supply	<b>315.5</b>	221.3	134.8	70.9	40.2	36.0	
Operating and maintenance	<b>49.7</b>	42.8	36.3	29.1	21.2	18.3	
Taxes — other than income	<b>22.5</b>	18.1	14.3	9.6	6.2	5.4	
Depreciation	<b>8.9</b>	7.1	6.6	6.8	6.5	6.0	
	<b>396.6</b>	289.3	192.0	116.4	74.1	65.7	43.3
Income deductions	<b>35.2</b>	29.4	24.5	25.4	17.1	16.3	16.7
Income taxes	<b>8.0</b>	6.4	5.3	6.8	2.3	3.2	
Net earnings	<b>19.7</b>	15.0	12.5	11.0	8.3	7.9	20.1
Preferred dividend requirements	<b>4.0</b>	3.3	1.4	1.4	.9	.9	
Balance attributable to common shares	<b>15.7</b>	11.7	11.1	9.6	7.4	7.0	17.5
Mid-year common equity investment	<b>86.7</b>	75.5	68.3	60.2	55.4	53.5	10.1



### Rates

During 1978, Canadian Western received approval from the Alberta Public Utilities Board for rate adjustments which took effect on April 1 and September 1 to pass on increases in the natural gas field price. (The field price is set by federal-provincial agreement.) The September rate change, approved on an interim basis and still awaiting final confirmation, also provided for inflationary increases in the costs of wages, materials and supplies and interest rates. Northwestern Utilities received board approval for a rate increase effective March 1 to meet the rise in field price. Both companies are waiting for board rulings on alternative methods of determining income tax chargeable to utility cost of service, and a proposal to have uniform rates for equivalent service throughout their respective systems.



## Gas Supply

The companies' main sources of natural gas are oil fields where solution gas, extracted in conjunction with oil production, is gathered and processed; gas fields from which wet gas is gathered and centrally processed before delivery to pipelines; and dry gas fields from which gas can be introduced almost directly into pipelines. Volumes of gas are also purchased from export companies and other natural gas pipeline companies. In addition, company-owned gas properties are a significant source of supply for meeting peak requirements.

During 1978 Canadian Western participated in the drilling of 21 gas wells of which 20 proved successful. Northwestern Utilities took part in the drilling of 39 wells, 25 of which were successful. Total cost of the drilling program was \$7.4 million. The costs of successful wells are added to assets; the balance, with Public Utilities Board approval, will be covered by border-flowback funds. Under the border-flowback program all Alberta gas producers receive a pro rata share of the extra revenues generated by the differential in price between gas exported to the U.S. and that marketed in Canada.

The companies currently own 861 billion cubic feet of gas and have under firm contract an additional 3,026 billion cubic feet. Another 3,043 billion cubic feet will be available for future purchase from fields where estimated gas producing life exceeds the term of the companies' existing gas purchase contracts. Agreements also exist which enable the utilities to call upon major gas exporters for very large quantities of base-load and peak-load gas.

## New Developments

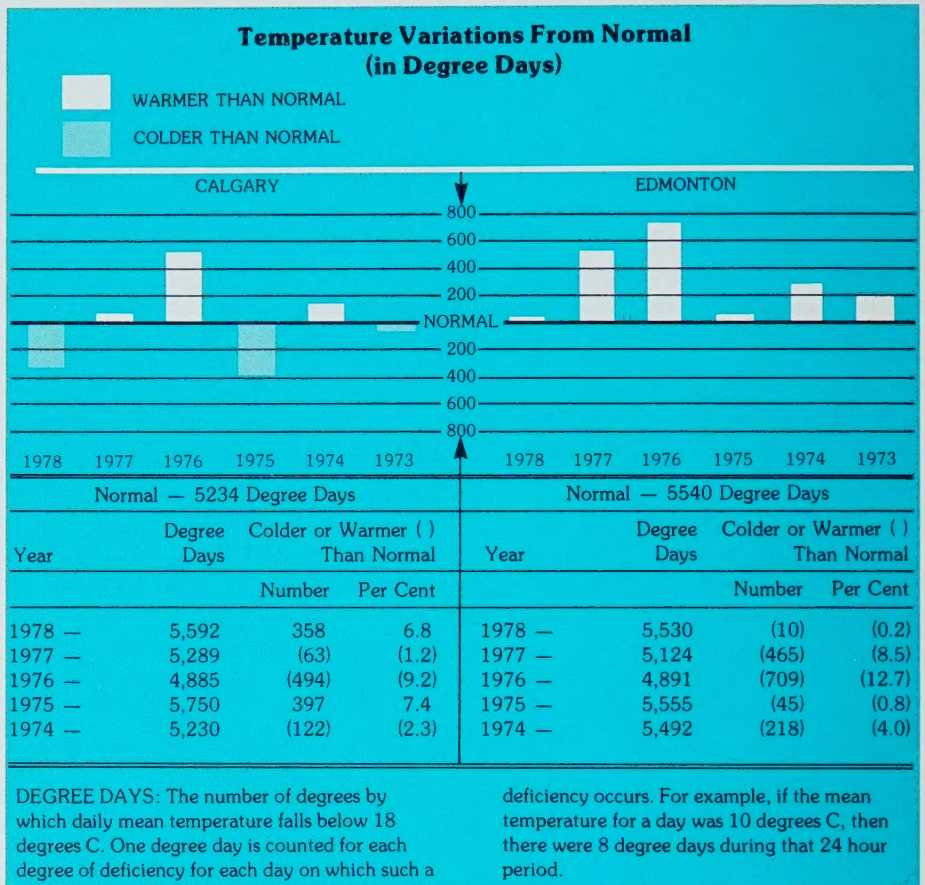
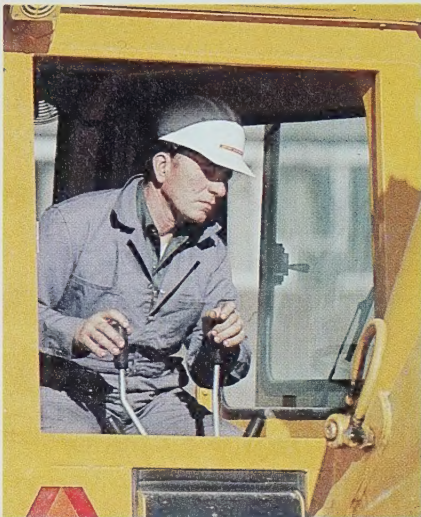
New projects planned for Alberta in the areas of oil sands and heavy oil extraction, petrochemical processing and pipelines and the influx of

population they entail will create a continuing demand for expanded utility services. The gas utilities, we believe, are well positioned with the financial and staff resources to meet the challenge of future growth.


Early in 1979 Northwestern Utilities purchased the natural gas distribution system of Beaver River Utilities Ltd. in northeastern Alberta where large-scale heavy oil development is planned. With the acquisition, Northwestern began serving approximately 1,700 new customers in Cold Lake, Grand Centre and Ardmore.

Natural gas, at present, is abundant in Alberta and for this reason strong pressures are being brought to bear to increase exports. The company is not opposed to exports, provided that existing safeguards ensuring adequate long-term supplies for Alberta are firmly maintained. A balance must be kept between making export markets available and thereby encouraging exploration, and placing future generations of Albertans at risk of prematurely running short of an essential resource, given the severity of the Alberta climate.





*A reel of copper conductor.*



# ELECTRIC OPERATIONS

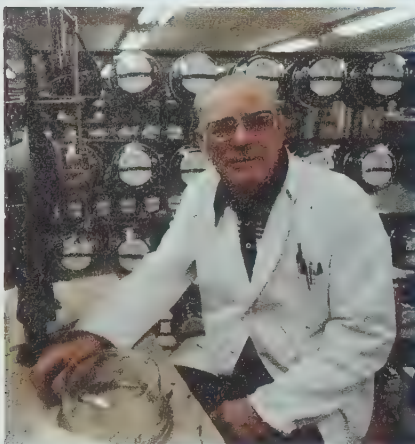
The company's main electrical utility subsidiary, Alberta Power Limited, serves 363 communities in east-central and northern Alberta and five communities in the Northwest Territories including the town of Hay River. An Alberta Power subsidiary, The Yukon Electrical Company Limited, serves 18 communities in the Yukon including the City of Whitehorse.

In 1978, 5,635 new electrical customers were added, bringing the year-end total to 112,490. Included in the sum were 22,430 farm customers of whom 21,391 were members of 168 rural electrification associations.

Energy sales to ultimate customers increased by 6.5 per cent to 2,512 million kilowatt hours. An additional 192 million kilowatt hours were sold to other utilities. The peak load decreased slightly to 520 megawatts from 524 megawatts in 1977. This was primarily the result of a distortion in 1977 caused by the temporary demand of approximately 20 megawatts at Syncrude prior to commissioning of its on-site generation.

Electric revenues were \$114.7 million, up from \$94 million a year earlier. A significant factor in revenue growth was that 1978 was the first full year of implementation of a general rate increase which became effective in Alberta in August, 1977.

No new rate applications were submitted by Alberta Power to the Public Utilities Board of Alberta during 1978 and, at the present time, none are anticipated until at least the latter part of 1979. In January, 1978 a decision on Alberta Power's 1977 rate application was received, confirming the revenue requested and the amount proposed by the company as a fair return on rate base. Pending at year-end was a decision by the Board on alternative methods of determining income tax chargeable to utility cost of service.



## Construction Activity

The electric operations' expenditures for additions to property, plant and equipment during the year were \$48.1 million. Of this total \$2.2 million was the final expenditure on the purchase of a \$20 million dragline for mining the Battle River coalfield. The 3500-ton walking dragline commenced operation in the spring of 1978.

Another \$14.7 million was spent, primarily on foundation work, on the latest addition to the Battle River Generating Station. The \$242 million Unit #5, which will more than double the station's generating capacity to 740 megawatts, is scheduled to be commissioned in 1981. Negotiations are well advanced with another utility on the purchase of half the output of the new unit commencing in 1981 on a five to seven year basis.

A 153-kilometre, 144-kV transmission line from the Monitor substation through Oyen to Empress will provide increased reliability to the southeastern portion of the province. The line was completed in July at a cost of \$3.4 million.

A 61-kilometre, 144-kV transmission line from Metiskow to Lloydminster was completed early in 1978 at a total cost of \$2.1 million.

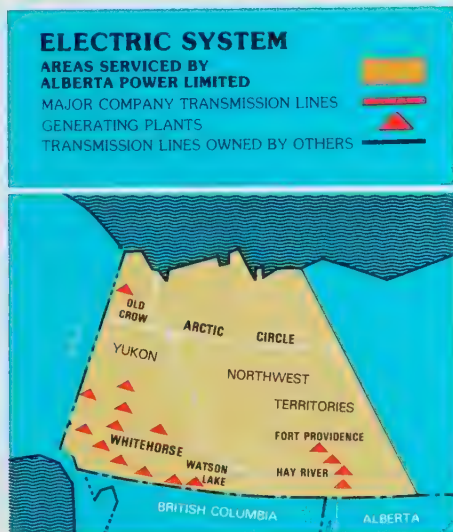
The first section of a 180-kilometre line from Vegreville to Bonnyville went into service in mid-year when 45 kilometres of the line from Vilna to Hairy Hill were energized at 72 kV. When completed in late 1979, the line will be energized at 144 kV to provide additional reliability and capacity in the Bonnyville area.

Altogether, \$8.5 million was expended on transmission and sub-transmission projects. A further \$12.1 million was employed for the construction and upgrading of various distribution systems. It should be noted in connection with construction activities that lengthening lead times experienced in obtaining necessary approvals on new transmission projects are adding to costs and hampering system reliability.

During the year, service franchises were renewed in 11 communities in Alberta including Grande Prairie, Fairview and Vermilion. Most franchise agreement renewals extend for 10 years.

## The Territories

Late in the year the federal government announced a subsidy to non-urban, non-government residential electric consumers in the Yukon and the Northwest Territories. The program subsidizes the first 700 kilowatt hours of residential consumption in smaller communities to the rate existing in the City of Whitehorse for Yukon communities, and in the City of Yellowknife for Northwest Territories communities.



In the Yukon, the Electric Public Utilities Board (Yukon Territory) reduced to 4.5 per cent the seven per cent rate increase granted The Yukon Electrical Company in its 1977 interim order.

In December, a general rate increase averaging 6.9 per cent for Alberta Power's customers in the Northwest Territories received final approval from the Public Utilities Board of the Northwest Territories.

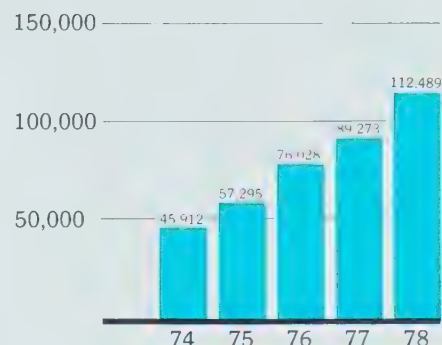
## New Development

Following public hearings, the Alberta Energy Resources Conservation Board announced in January, 1979 that it was recommending to the provincial cabinet approval of Alberta Power's application for the construction of the Sheerness generating station, with the first unit to be commissioned in 1985 and the second in 1986. Sheerness initially will have more than enough capacity to supply Alberta Power's needs, and commercial arrangements for the remaining capacity will be negotiated with the other participants in the provincial power grid to meet their forecast requirements. The new generating units will be of 375-megawatt size, which conforms to the standard recommended by the Alberta Electric Utility Planning Council, and will thus be compatible with generating stations of other utilities in the province.

The company is closely monitoring resource developments planned within or near its designated service areas in the Fort McMurray and Cold Lake regions of Alberta. The designation of new service territories is a matter of considerable importance to the company, particularly when these areas include the potential for concentrated loads associated with oil sands development. Although Alberta Power has been assigned somewhat more than one-half of the designated service area within the province, the area contains only about 15 per cent of the existing provincial load and population. Concentrated load additions can serve to reduce cost differentials which exist between the unit cost of service in rural areas and service costs for more densely populated centres.

## Electric Revenues

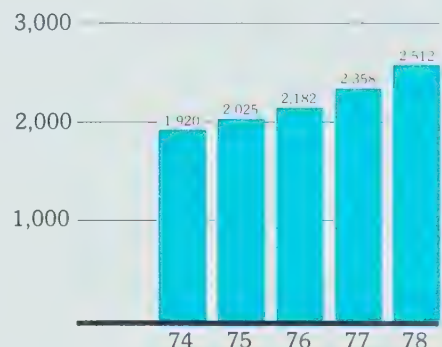
(Thousands of dollars)



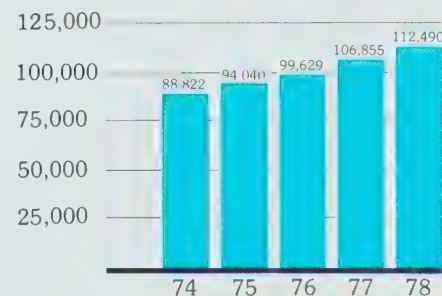
In the chart above electric revenues include only those resulting directly from the sale of electric energy. Electric revenues per financial statements include other miscellaneous operating revenues

## Electric Sales

(Millions of kilowatt hours)

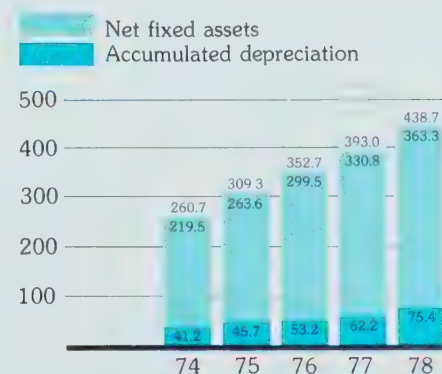


## Electric Customers



## Net Fixed Assets

(Millions of dollars)



## Electric Operations Earnings Contribution

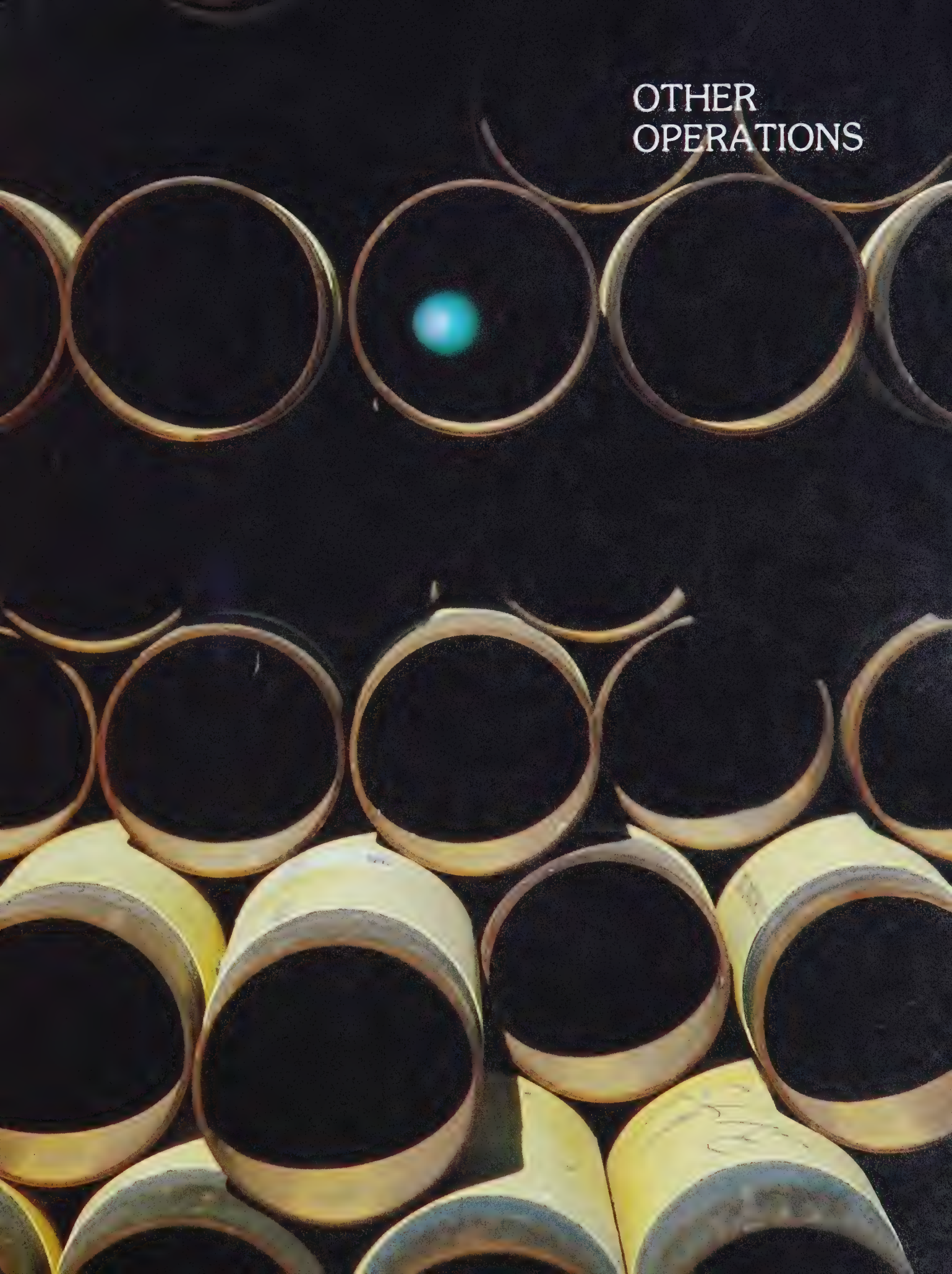
						Annual Growth Rate 1973-1978
	1978	1977	1976	1975	1974	1973
	(Millions of dollars)					(per cent)
Electric revenues	<b>114.7</b>	93.9	78.1	57.9	46.3	38.3
Operating expenses						
Operating and maintenance	<b>51.9</b>	42.3	35.4	27.0	22.2	16.3
Taxes — other than income	<b>4.2</b>	3.7	2.7	2.2	1.8	1.4
Depreciation	<b>13.8</b>	11.4	8.8	6.3	6.4	4.9
	<b>69.9</b>	57.4	46.9	35.5	30.4	22.6
	<b>44.8</b>	36.5	31.2	22.4	15.9	15.7
Income deductions	<b>8.7</b>	10.2	12.3	7.2	8.0	7.0
Income taxes	<b>11.1</b>	5.8	3.1	1.6	.1	1.3
Net earnings	<b>25.0</b>	20.5	15.8	13.6	7.8	7.4
Preferred dividend requirements	<b>6.3</b>	5.1	3.0	2.9	.6	.6
Balance attributable to common shares	<b>18.7</b>	15.4	12.8	10.7	7.2	6.8
Mid-year common equity investment	<b>113.2</b>	98.8	84.8	65.3	55.9	51.6



During the year the federal government proposed to discontinue its policy of refunding 95 per cent of income tax paid by investor-owned utilities (government-owned utilities pay no income taxes). In Alberta, the refunded taxes are passed on to consumers. Following vigorous protests by the industry and others concerned, the federal government has agreed to continue refunds but at the reduced rate of 50 per cent. The logic of penalizing consumers served by investor-owned utilities is unclear and, in the company's view, requires further re-examination by Ottawa. The Alberta government will continue to refund all provincial income tax paid by the private utilities and will finance the acceleration of refunds to buffer the immediate impact of the federal action on consumers within Alberta.

*Natural gas steel pipe with Yellow-Jacket corrosion protection, stacked in a pipe yard in Edmonton.*

OTHER  
OPERATIONS



### **CU Engineering Limited**

During 1978, CU Engineering was engaged on a variety of projects relating to the design and construction of rural gas systems, major transmission line projects, municipal water and sewage systems, and the evaluation and upgrading of natural gas systems. All of the company's work was in Alberta, with the exception of a gas transmission line project in British Columbia. The company is actively seeking overseas markets for its services, especially in the areas of utility transmission and distribution engineering.

The several large-scale energy projects planned for Alberta are expected to increase demand for engineering consulting services in the province by late 1979.

CU Engineering, which was formed in 1975, offers to utility owners and users a wide range of services, including the preparation of feasibility studies, design, procurement and construction inspection. In addition to designing and commissioning new utility systems, the company will operate the systems on a contract basis. The company employs its own experienced personnel and has access to additional skills from other Canadian Utilities subsidiaries.

### **CU Ethane Limited**

The Edmonton ethane extraction plant, owned jointly by CU Ethane Limited and Dome Petroleum Limited, began

operations in June with the official start-up on July 1. The July 1 to September 30 start-up period allowed for minor modifications to enable the plant to meet design criteria. Cost of service payments under a long-term contract with Alberta Gas Ethylene commenced October 1.

During the year, agreement was reached with Imperial Oil Limited to process at the plant natural gas from Imperial Oil's Golden Spike oil field. CU Ethane and Dome shared construction costs of a 4.83-kilometre pipeline to transport Golden Spike gas to the plant site. The companies also installed special facilities to extract natural gas liquids (propane pluses) from the liquid-rich Golden Spike gas before it enters the main processing stream.

Daily production averages at the plant have been in excess of 16,000 barrels of ethane and 10,000 barrels of propane pluses extracted from 278 million cubic feet of natural gas. The plant can accept up to 345 million cubic feet a day of inlet gas.

### **CU Resources Limited**

CU Resources during 1978 continued its oil and gas exploration and development program on properties acquired in 1976 from Canadian Western Natural Gas Company Limited and Northwestern Utilities Limited.

Company-owned production from all properties in which CU Resources has an interest was approximately 425 barrels a day of heavy oil. The oil is sold to the Alberta Petroleum Marketing Commission.



*Dials for residential gas meters. Gas consumption, currently measured in thousands of cubic feet and therms, will be converted to gigajoules when Canadian Western and Northwestern Utilities adopt metric measurement in 1979. A gigajoule is approximately equivalent to the amount of energy in 1000 cubic feet of natural gas.*

# FINANCIAL REVIEW



## Earnings Per Common Share Increase 22%

Net earnings from consolidated operations attributable to common shares were as follows:

	Total Amount (\$ Millions)	Earnings Per Share (\$)	Per Cent Increase Over Prior Year	
			Total	Per Share
1978	35.6	1.97	28	22
1977	27.7	1.61	17	4
1976	23.7	1.55	27	7

The fully diluted per share earnings are based on the average number of shares outstanding in each year and reflect the issue of 1.35 million shares in June, 1978 and 2 million shares sold in November, 1976.

Growth in earnings per share should be at least one-half of the normal return on book common equity per share if the company continues a policy of reinvesting close to one-half of its earnings in new plant and equipment and if the regulated levels of earnings are achieved. Thus a deviation from the resulting seven per cent to eight per cent growth rate is due to other events recorded in either the prior or current year. It was mentioned in the 1977 annual report that the winter weather in Alberta had been abnormally warm. In the year just concluded, near-normal temperatures were recorded, causing

the increase over the previous year to rise well in excess of eight per cent. To the extent the net proceeds from the issue of additional common shares are above the net book value of existing shares, the reported earnings per common share will include a return on this gain. An issue of common shares in 1978 was made at better than net book value per share.

Inasmuch as the utility operations of the company are regulated on a projected test year, all elements of the cost of service must be forecasted with considerable care and attention. The accuracy of these projections is attested by achievement in 1978 of close to the regulated return on common equity that was considered reasonable for each of the major utility subsidiaries as established by the most recent regulatory orders.

Continuing the practice established in 1977, the operations sections of this report show the earnings attributable to common shares as contributed by each segment of the company. The growth record of the past five years is as shown below:

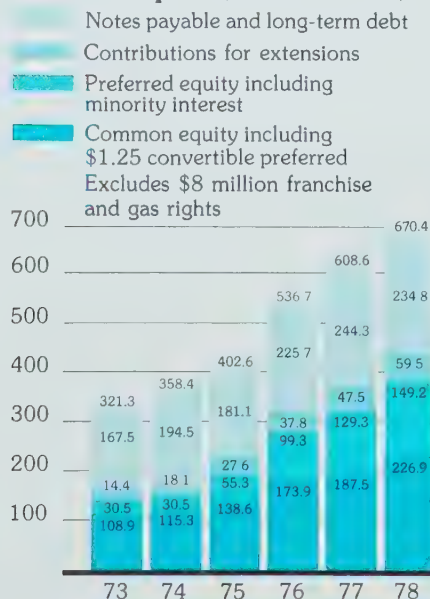
	Electric	Gas	Other	Total
Five-year annual growth rate	22%	17%	—	21%
1978	\$18.7	\$15.7	\$1.2	\$35.6
1977	15.4	11.7	0.6	27.7
1976	12.8	11.1	0.1	24.0
1975	10.7	9.6	0.2	20.5
1974	7.2	7.4	0.1	14.7
1973	6.8	7.0	—	13.8

The annual growth rate per common share over the same period was 15 per cent, somewhat lower than the earnings growth in absolute terms due to issues of additional shares in this period.

## Common Dividends Raised

Continuing the record of regular dividend increases which commenced in 1972, the quarterly dividend paid on common shares was raised again in the fourth quarter of 1978 from 22¼¢ to 24½¢, an increase of 10 per cent. Total dividends declared for the common shareholders was \$16.4 million, an increase of 14 per cent in the year. The

## Invested Capital (Millions of dollars)

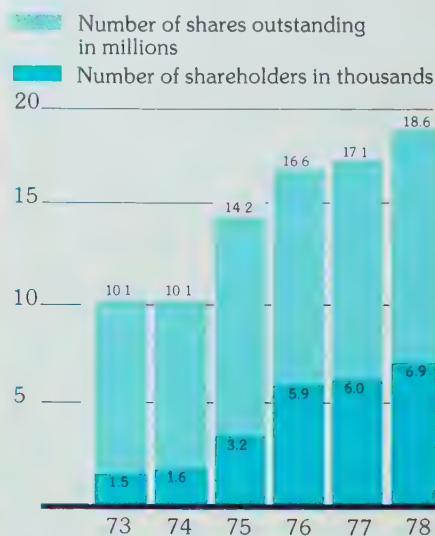


## Capital Program (Millions of dollars)



## Common Shares Outstanding and Number of Shareholders

as at December 31, 1978



currently indicated annual dividend per share of \$0.98 represents a continuation of the practice of distributing approximately one-half of the current year's earnings to the shareholders.

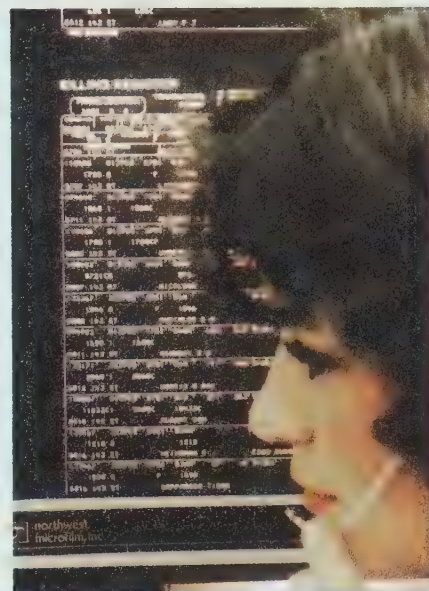
### Investment by Common Shareholders Higher

Earnings not distributed as a dividend are re-employed in the company. In the five-year period 1973 to 1978, the common shareholders equity per share has grown from \$8.04 to \$12.22 for an annual average rate of growth of 8% per cent. In the same period the total common equity has more than doubled to \$226.9 million. This increase has resulted from new issues of common shares in addition to earnings retained in the business. The number of shares available to the public has increased five-fold in this period and the shares now trade actively on the major Canadian stock exchanges. At the close of 1978, there were 6,882 shareholders in Canada and 50 shareholders outside of Canada. The issue of additional common shares in the year contributed substantially to the addition of 931 Canadian shareholders over the 1977 level.

### Rate Changes

For the first time in recent years, a lessening in the tempo of rate case

preparation and regulatory appearances has been noted. At the present time, final decisions with respect to the 1978 test year have been received for all companies except Canadian Western Natural Gas Company Limited which has been applying interim rates since September 1, 1978. While inflationary pressures continue to affect the cost of labor, materials and services, there has been some moderation in the increase in 1978. However, the termination of the Anti-Inflation Act (Canada) can be expected to provide an upward push in labor and other costs. This is particularly so in Alberta where levels of unemployment have remained well below the national average. The current status of regulatory awards is as follows:

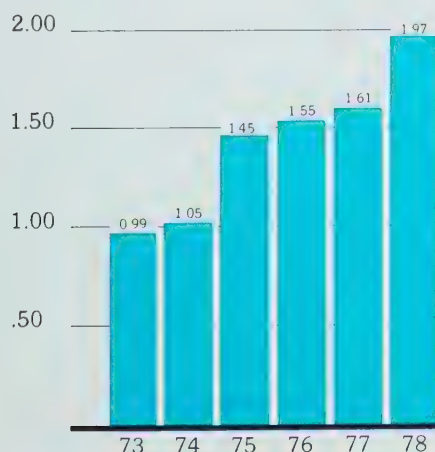


	Date	Test Year	Rate Base (Millions of Dollars)	Return on Rate Base (Per cent)	Implied Equity Rate of Return (Per cent)
<b>Final Order</b>					
Alberta Power Limited	Jan./78	1978	317.2	10.3	14.2
Northwestern Utilities Limited	Apr./78	1978	134.2	10.2	14.2
<b>Interim Order</b>					
Canadian Western Natural Gas Company Limited	Sept./78	1978	113.6	10.7	14.4

### Earnings Per Share

(Before extraordinary items fully diluted)

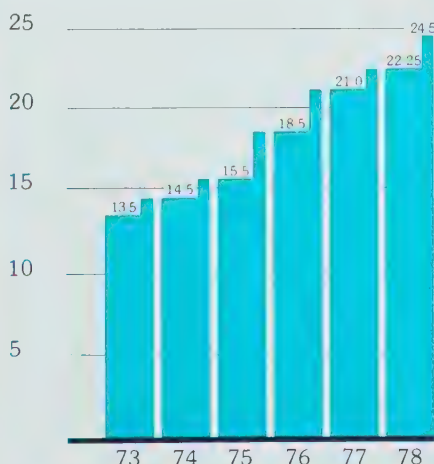
Annual growth rate — 1973 to 1978: 14.8% (in dollars)



### Dividends Per Common Share

(Quarterly rate)

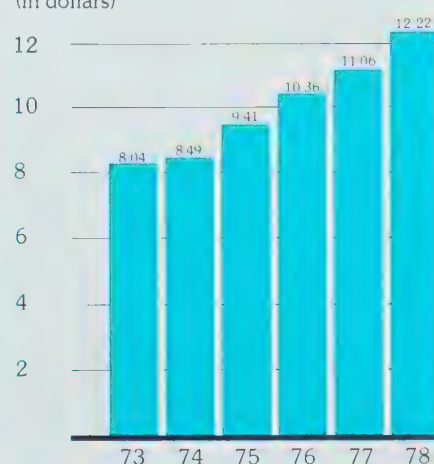
Annual growth rate — 1973 (First Quarter) to 1978 (Fourth Quarter): 12.7% (in cents)

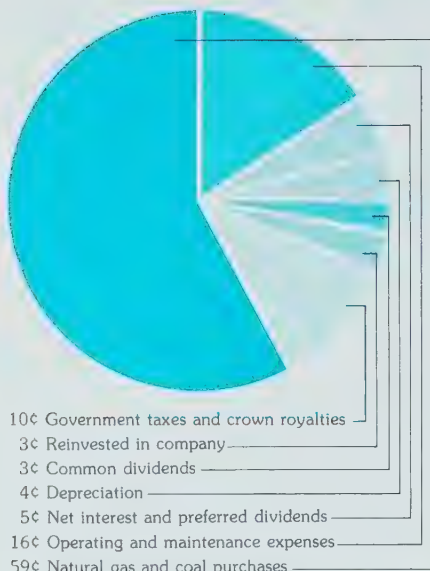


### Common Shareholders' Equity Per Share

(Year-end fully diluted basis)

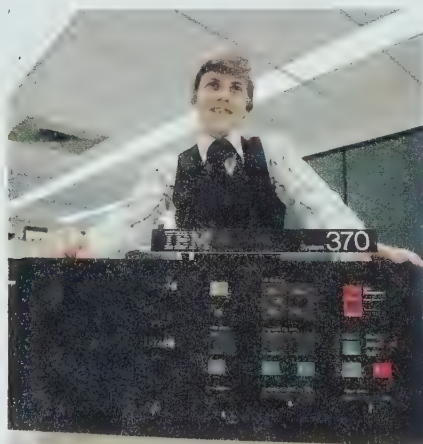
Annual growth rate — 1973 to 1978: 8.7% Excludes \$8 million franchise and gas rights as per regulatory practice. (in dollars)





Increases in the field price of natural gas have also been recovered through separate applications and approvals. Apart from requests to recover increasing costs of service, the utility subsidiaries have been involved in hearings to determine regulatory treatment of income tax to be included in cost of service, and to consider the suggestion by the gas utilities that "postage stamp" or uniform rates be adopted for natural gas utility service throughout Alberta. The timing of decisions with respect to these hearings is unknown.

While there is now a good possibility of a temporary lull in the level of requests for rate relief, it is unlikely the company would be able to avoid the need to request additional revenues in the future even if inflation were to return to levels experienced before the 1970's. The cumulative impact of recent inflation levels makes itself felt when existing utility equipment must be replaced. Under the existing regulatory practice in Alberta, the customer does not provide any of the funds for new utility plants until the facility is complete and in service. Spending on a new thermal plant can span a period of at least five years, thus the impact of inflation on utility rates tends to be deferred until completion of major additions, causing irregular and occasionally substantial rises in rates.



## New Construction Accelerates

Outlay on new plant and equipment was \$108 million in 1978, 10 per cent above the \$98 million recorded in 1977. Capital expenditures are expected to exceed \$200 million in each of the next five years. About one-half of the demand for funds in the company was obtained from operations in 1978. As the spending program accelerates in the next five years, less than 30 per cent will be raised internally, placing a heavier demand on access to external funds. This forecast assumes construction of the Sheerness coal-fired electric generating units #1 and #2 for start-up in the mid-1980's and that one-half of both units will be owned and financed by the company.

## Financing Growth

CU Ethane Limited placed \$20 million of term preferred shares privately in June, 1978. The dividend rate on the preferred shares is based on one-half of the prime commercial bank lending rate plus 1 1/4 per cent. No repayment of this issue is required in the first 10 years. Since the contractual cost of service arrangement with respect to the ethane facility also recovers the cost of capital other than the deemed common equity capital, on a basis related to the prime commercial bank lending rate, the company is not exposed to fluctuations in this rate.

The exercise of nearly all of the share purchase warrants prior to the May 15, 1978 expiry date yielded \$1.4 million to the company.

In June, 1978 an issue of one million common shares to the Canadian public and a further 350 thousand shares to an affiliate of IU International was made at a price of \$14 7/8 per share for a total value of \$20 million. It is expected that debt financings will be required in 1979 in keeping with the goal of keeping a mix of capital where common equity would be 35 per cent of the total, preferred equity about 20 per cent and the balance in the form of long-term debt.

*A calorimeter, used to measure the heating value of natural gas samples.*

1050

1200

1350

1100

1150

1250

1300

1400

1450

BHL

6-22

990

BHL

#11-3

986

BHL

10-24

1069

ACURAC

1069

2 CASE

24-A

30-A

COND

10-7

BAL

10-7

BHL

10-14

BAL

10-14

# CONSOLIDATED STATEMENT OF EARNINGS

Year ended December 31, 1978 with comparative figures for 1977

	1978	1977
	Thousands	
<b>Revenues</b>	<b>\$554,176</b>	<b>\$415,373</b>
<b>Operating Expenses</b>		
Natural gas supply (Note 1)	315,509	221,245
Operating and maintenance	107,169	87,167
Taxes — other than income	26,629	21,836
Depreciation	23,148	18,782
	<b>472,455</b>	<b>349,030</b>
	<b>81,721</b>	<b>66,343</b>
<b>Allowance for Funds Used During Construction</b>	<b>4,743</b>	<b>2,331</b>
<b>Other Income</b>	<b>2,539</b>	<b>1,309</b>
	<b>89,003</b>	<b>69,983</b>
<b>Interest Expense</b>	<b>22,425</b>	<b>21,456</b>
	<b>66,578</b>	<b>48,527</b>
<b>Income Taxes (Note 2)</b>	<b>20,073</b>	<b>12,499</b>
	<b>46,505</b>	<b>36,028</b>
<b>Minority Interests</b>	<b>1,460</b>	<b>860</b>
<b>Net Earnings before Extraordinary Item</b>	<b>45,045</b>	<b>35,168</b>
<b>Extraordinary Item (Note 3)</b>		<b>1,592</b>
<b>Net Earnings</b>	<b>45,045</b>	<b>33,576</b>
<b>Preferred Dividend Requirements</b>	<b>9,395</b>	<b>7,487</b>
<b>Balance Attributable to Common Shares</b>	<b>\$ 35,650</b>	<b>\$ 26,089</b>
<b>Earnings — Dollars Per Common Share (Note 4)</b>		
Basic		
Net earnings before extraordinary item	\$ 1.98	\$ 1.64
Extraordinary item		.09
Net earnings	<b>\$ 1.98</b>	<b>\$ 1.55</b>
Fully diluted		
Net earnings before extraordinary item	\$ 1.97	\$ 1.61
Extraordinary item		.09
Net earnings	<b>\$ 1.97</b>	<b>\$ 1.52</b>

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

# CONSOLIDATED BALANCE SHEET

December 31, 1978 with comparative figures for 1977

	1978	1977
	Thousands	
<b>ASSETS</b>		
<b>Current Assets</b>		
Cash and short-term deposits	\$ 10,855	\$ 14,966
Accounts receivable (Note 5)	98,263	70,220
Materials and supplies — at average cost	11,672	10,696
Natural gas stored — at cost	412	5,153
Prepaid expenses	2,183	3,795
	<b>123,385</b>	104,830
<b>Trust Assets Held for Rural Co-operative Lines, Per Contra</b>	<b>9,112</b>	8,011
<b>Trust Assets Held for Income Tax Rebate for Consumers, Per Contra</b>	<b>1,607</b>	4,722
<b>Property, Plant and Equipment at Cost Less Accumulated Depreciation (Note 6)</b>	<b>700,078</b>	618,799
<b>Deferred Income Taxes (Note 2)</b>		319
<b>Deferred Expenses (Note 7)</b>	<b>9,472</b>	7,601
	<b>\$843,654</b>	<b>\$744,282</b>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
<b>Current Liabilities</b>		
Due to bank	\$ 20,765	\$ 8,948
Accounts payable and accrued liabilities	102,721	79,569
Dividends payable	2,868	1,842
Long-term debt — current maturities (Note 8)	5,120	2,580
Note payable to affiliated company	150	3,500
Deposits	3,063	2,763
Income and other taxes	12,361	9,315
	<b>147,048</b>	108,517
<b>Amounts Held in Trust, Per Contrasts</b>	<b>10,719</b>	12,733
<b>Long-Term Debt (Note 8)</b>	<b>233,718</b>	244,323
<b>Contributions for Extensions to Plant</b>	<b>59,544</b>	47,453
<b>Deferred Income Taxes (Note 2)</b>	<b>497</b>	
<b>Other Liabilities</b>	<b>8,003</b>	6,410
<b>Minority Interests (Note 9)</b>	<b>40,008</b>	20,008
<b>Shareholders' Equity</b>		
Preferred shares (Note 10)	<b>109,182</b>	109,300
	1978	1977
Common shares (Note 11)	<b>\$160,613</b>	\$139,143
Retained earnings (Note 8)	<b>74,322</b>	56,395
	<b>234,935</b>	195,538
	<b>344,117</b>	304,838
	<b>\$843,654</b>	<b>\$744,282</b>

On behalf of the Board:

**J. E. Maybin**/Director

**D. R. B. McArthur**/Director

# CONSOLIDATED STATEMENT OF CHANGES IN FINANCIAL POSITION

Year ended December 31, 1978 with comparative figures for 1977

	1978	1977
	<b>Thousands</b>	
<b>Sources of Working Capital</b>		
Net earnings before extraordinary item	<b>\$ 45,045</b>	\$ 35,168
Add non-cash items, principally depreciation	<b>25,424</b>	20,679
	<b>70,469</b>	55,847
Provided from operations		24,780
Issue of long-term debt		29,068
Issue of preferred shares	<b>20,000</b>	
Issue of preferred shares by subsidiary company	<b>20,613</b>	4,459
Issue of common shares	<b>14,220</b>	10,341
Increase in contributions for extensions to plant	<b>1,462</b>	1,124
Disposition of property, plant and equipment	<b>955</b>	(1,157)
Other	<b>127,719</b>	124,462
<b>Uses of Working Capital</b>		
Purchase of property, plant and equipment	<b>108,018</b>	97,527
Reduction in long-term debt	<b>10,605</b>	8,811
Reduction in note payable to affiliated company		3,500
Dividends — preferred	<b>9,927</b>	7,569
— common	<b>16,371</b>	14,417
Redemption and conversion of preferred shares	<b>118</b>	878
Increase in deferred expenses	<b>2,656</b>	2,530
	<b>147,695</b>	135,232
<b>Decrease in Working Capital</b>	<b>\$ 19,976</b>	\$ 10,770

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

# CONSOLIDATED STATEMENT OF RETAINED EARNINGS

Year ended December 31, 1978 with comparative figures for 1977

	1978	1977
	Thousands	
<b>Balance at Beginning of Year</b>	<b>\$ 56,395</b>	\$63,921
<b>Add Net Earnings</b>	<b>45,045</b>	33,576
	<b>101,440</b>	97,497
<b>Deduct</b>		
Dividends		
Preferred shares	<b>9,927</b>	7,569
Common shares	<b>16,371</b>	14,417
	<b>26,298</b>	21,986
Share issue expense less related income taxes of \$373 in 1978 and \$484 in 1977	<b>820</b>	1,549
Write-off of excess cost of shares of subsidiary companies over underlying net book value at December 31, 1971		17,567
	<b>27,118</b>	41,102
<b>Balance at End of Year</b>	<b>\$ 74,322</b>	\$56,395

See accompanying summary of significant accounting policies and notes to consolidated financial statements.

# SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

December 31, 1978

## **Basis of consolidation**

The consolidated financial statements include the accounts of the company and all subsidiary companies. All material inter-company balances and transactions have been eliminated.

## **Property, plant and equipment**

Property, plant and equipment includes cost of land, resource properties, buildings and equipment. The gross cost of additions includes an allowance for funds used during construction based on the debt and equity cost of capital components.

Depreciation is provided on classes of assets at various rates on a straight line basis over the estimated useful lives of the assets. In accordance with the orders of regulatory bodies, depreciation is provided after giving effect to contributions for extensions to plant. The major assets are depreciated at rates varying from 2.17% to 6.6%. Certain resource properties are depreciated in part on a unit withdrawal basis.

On retirement of depreciable plant, the accumulated depreciation is charged with the cost of the retirement unit less net salvage. Gains and losses on extraordinary retirements are recognized as extraordinary items in the financial statements.

## **Deferred expenses**

Expenses incurred in connection with the issue of long-term debt are amortized over the periods that the debt is outstanding.

Deferred charges relating to gas exploration include expenditures related to the development of gas

reserves. Costs resulting in a successful venture are capitalized and depreciated on a unit withdrawal method. With the approval of the Public Utilities Board of Alberta, costs of unsuccessful exploration, net of income taxes, incurred by the gas subsidiaries are charged against the amounts received under the Natural Gas Pricing Agreement Act.

Goodwill consists of the excess cost of shares issued over the underlying net book value of shares acquired in 1972 from minority shareholders of a subsidiary company and is being amortized over a period of 40 years.

Other deferred charges are subject to amortization over varying periods of time not exceeding 40 years.

## **Income taxes**

In fixing rates, except for the matters referred to below, the utility companies recover only taxes payable currently and, accordingly, to the extent that capital cost allowances are claimed in excess of recorded depreciation, there has been a related reduction in the amount of income taxes otherwise payable which has not been reflected in the financial statements. The reduction will become a charge to be borne by the consumer in future years when recorded depreciation exceeds capital cost allowances claimed for income tax purposes.

The companies are permitted to claim deferred income taxes in respect to acquisition of natural gas rights, deferred gas costs, rate case expenses and share issue costs.

## **Natural gas supply**

The Province of Alberta enacted the Natural Gas Rebates Act effective January 1, 1974 to shelter the majority of Alberta natural gas consumers from the full impact of significant price increases for natural gas. Under the provisions of the Act, the gas utilities are reimbursed for the excess price paid to their suppliers over the support price. The statement of earnings is charged with the net cost of natural gas.

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 1978

## 1. Natural gas supply

The natural gas supply is net of Alberta government rebate amounting to \$95,301,000 in 1978 and \$62,543,000 in 1977.

## 2. Income taxes

The provision for income taxes in the consolidated statement of earnings includes a deferred tax draw-down of \$289,000 in 1978 (\$1,000 in 1977).

Total deferred income taxes increased by \$9,598,000 during 1978 (\$7,291,000 in 1977). The cumulative amount of deferred income taxes to December 31, 1978 is \$76,842,000 of which \$497,000 has been recorded in the accounts as a deferred credit, \$48,000 as a reduction in deferred expenses and income and other taxes payable are reduced by \$92,000.

## 3. Extraordinary item

The extraordinary item in 1977 amounting to \$1,592,000 net of income taxes of \$1,515,000 represents a non-recurring loss of expenditures in Canadian Arctic Gas Study Limited.

## 4. Earnings per common share

In the fully diluted earnings per common share calculation, the assumption is made that warrants for the purchase of common shares at \$9 had been exercised at the beginning of each year and that the funds derived therefrom had been invested to produce an annual rate of 8% before applicable income taxes. In addition, the calculation assumes conversion of the shares reserved for the employees' share purchase plan. The average number of shares used in the calculation of fully diluted earnings per common share was 18,145,908 for 1978 and 17,311,673 for 1977.

## 5. Accounts receivable

	1978	1977
	(Thousands)	
Consumer accounts, gas and electric	<b>\$64,364</b>	\$47,187
Receivable from the Province of Alberta	<b>14,181</b>	12,258
Other receivables and deposits	<b>19,718</b>	10,775
	<b><u>\$98,263</u></b>	<u>\$70,220</u>

## 6. Property, plant and equipment

	1978		1977	
	Accumulated Depreciation and Depletion		Accumulated Depreciation and Depletion	
	Cost		Cost	
	(Thousands)		(Thousands)	
Gas utility plant and equipment	<b>\$407,553</b>	<b>\$107,604</b>	\$361,969	\$ 99,262
Electric utility plant and equipment	<b>437,354</b>	<b>75,264</b>	391,711	61,990
Other plant and equipment	<b>28,588</b>	<b>947</b>	16,855	426
Undertakings, franchise and gas rights	<b>8,000</b>		8,000	
Land	<b>2,398</b>		1,942	
	<b><u>\$883,893</u></b>	<b><u>\$183,815</u></b>	<u>\$780,477</u>	<u>\$161,678</u>
	<b><u>\$700,078</u></b>		<u>\$618,799</u>	

## 7. Deferred expenses

	1978	1977
	(Thousands)	
Debt discount and expenses	<b>\$3,526</b>	\$3,859
Gas exploration	<b>4,789</b>	2,436
Goodwill	<b>475</b>	490
Other	<b>682</b>	816
	<b><u>\$9,472</u></b>	<u>\$7,601</u>

## 8. Long-term debt

	1978	1977
	(Thousands)	
Canadian Utilities Limited		
Sinking fund debentures 8 $\frac{3}{8}$ % to 11 $\frac{1}{2}$ % due to 2002	<b>\$142,701</b>	\$146,897
Alberta Power Limited		
First mortgage sinking fund bonds 4 $\frac{1}{4}$ % to 6 $\frac{1}{2}$ % due to 1992	<b>31,038</b>	31,143
Sinking fund debentures 7 $\frac{1}{4}$ % to 9 $\frac{5}{8}$ % due to 1991	<b>20,863</b>	21,573
Northwestern Utilities Limited		
First mortgage sinking fund bonds 4 $\frac{3}{4}$ % to 9 $\frac{3}{4}$ % due to 1994	<b>20,001</b>	21,306
Sinking fund debentures 6 $\frac{3}{4}$ % to 7 $\frac{1}{4}$ % due to 1985	<b>2,706</b>	3,320
Canadian Western Natural Gas Company Limited		
First mortgage sinking fund bonds 5 $\frac{3}{8}$ % to 7% due to 1992	<b>13,914</b>	14,543
Sinking fund debentures 9 $\frac{3}{4}$ % due 1990	<b>7,615</b>	8,121
Total long-term debt	<b>238,838</b>	246,903
Deduct current maturities	<b>5,120</b>	2,580
Long-term debt less current maturities	<b><u>\$233,718</u></b>	<u>\$244,323</u>

Annual requirements for long-term debt maturities have been reduced by bonds and debentures purchased for future sinking fund payments and exclude requirements which may be satisfied by certifications of property additions.

Annual requirements for each of the following years are:

	(Thousands)
1979	\$ 5,120
1980	4,359
1981	8,710
1982	12,083
1983	14,198

The bond and debenture indentures executed by the company and its subsidiaries place limitations on the company and its subsidiaries, including restrictions on the payment of dividends. Of the consolidated retained earnings at December 31, 1978, approximately \$59,624,000 (1977 — \$42,025,000) were free from such restrictions.

## 9. Minority interests

	1978	1977
	(Thousands)	
Minority interest in the preferred shares of subsidiaries:		
Northwestern Utilities Limited	<b>\$10,500</b>	\$10,500
Canadian Western Natural Gas Company Limited	<b>9,508</b>	9,508
CU Ethane Limited	<b>20,000</b>	
	<b><u>\$40,008</u></b>	<u>\$20,008</u>

## 10. Preferred shares

Authorized:

40,000 5% Cumulative Redeemable Preferred Shares of the par value of \$100 each.

150,000 series preferred shares of the par value of \$100 each, issuable in series, of which 15,000 shares have been designated as Cumulative Redeemable Preferred Shares 4¼% Series and 50,000 shares designated as Cumulative Redeemable Preferred Shares 6% Series.

9,947,280 series second preferred shares of the par value of \$25 each, issuable in series, of which 1,152,000 shares have been designated as 10¼% Cumulative Redeemable Second Preferred Shares Series A, 1,600,000 shares have been designated as 9.24% Cumulative Redeemable Second Preferred Shares Series B, and 1,195,280 have been designated as 7.30% Cumulative Redeemable Second Preferred Shares, Series C.

Issued:

	1978		1977	
	Number	Value (Thousands)	Number	Value (Thousands)
5% preferred shares, redeemable at a premium of 4%	40,000	\$ 4,000	40,000	\$ 4,000
Preferred shares 4¼% series redeemable at a premium of 2½%	15,000	1,500	15,000	1,500
Preferred shares 6% series redeemable at a premium reducing from 3% to 1%	50,000	5,000	50,000	5,000
10¼% second preferred shares Series A redeemable at a premium reducing from 5% to par	1,152,000	28,800	1,152,000	28,800
9.24% second preferred shares Series B redeemable at a premium reducing from 5% to par	1,600,000	40,000	1,600,000	40,000
7.30% second preferred shares Series C redeemable at a premium reducing from 4% to par	1,195,280	29,882	1,200,000	30,000
		<u>\$109,182</u>		<u>\$109,300</u>

The preferred shares may be redeemed at the option of the company subject to the premiums listed plus outstanding dividends.

The company is required to make all reasonable efforts to purchase for cancellation in the open market 12,000 of the 10¼% series, 12,000 of the 9.24% series and 9,000 of the 7.30% series, in each quarter at a price not exceeding \$25 per share plus costs of purchase, such an obligation to carry over to the succeeding quarterly periods in the same year. If after all reasonable efforts the company is unable so to purchase an aggregate of 48,000 of the 10¼% series, 48,000 of the 9.24% series and 36,000 of the 7.30% series in the four quarters of any year, the company's obligation to purchase shares with respect to such years is extinguished. During the year the company redeemed 4,720 shares of the 7.30% series reducing the capital of the company by \$118,000.

## 11. Common shares

Authorized:

30,000,000 shares without nominal or par value

Issued:

	1978		1977	
	Number	Value (Thousands)	Number	Value (Thousands)
Balance at beginning of year	17,121,584	\$139,143	16,633,504	\$134,684
Issued on conversion of \$1.25 preferred shares			65,788	658
Issued on exercise of share purchase warrants	154,284	1,389	422,292	3,801
Issued during the year	1,350,000	20,081		
Balance at end of year	18,625,868	\$160,613	17,121,584	\$139,143

At December 31, 1978 the company has reserved 97,026 unissued common shares for issuance under an employee share purchase plan. The rights to purchase are exercisable for \$12.26 per share on December 31, 1979.

## 12. Remuneration of directors and officers

During the year ended December 31, 1978 the company paid aggregate remuneration of \$80,000 to 14 directors as directors (\$80,000 to 15 directors in 1977) and \$467,000 to seven officers as officers (\$451,000 to seven officers in 1977). Three officers were also directors.

## 13. Commitments and contingencies

The cost of the company's planned construction and expansion program for 1979 will amount to approximately \$188,000,000 of which \$84,000,000 is presently under contract. Total commitments under contract for 1979 and future years are approximately \$170,000,000.

The company has a pension plan covering substantially all its employees. The aggregate unfunded past service liability amounted to approximately \$10,734,000 at December 31, 1978. Of this amount \$5,845,000 must be funded by December 31, 1981 and the balance over a period not exceeding 14 years.

## 14. Comparative figures

Certain of the 1977 comparative figures have been reclassified to conform with the financial statement presentation adopted for 1978.

# AUDITORS' REPORT TO THE SHAREHOLDERS

We have examined the consolidated balance sheet of Canadian Utilities Limited as of December 31, 1978 and the consolidated statements of earnings, retained earnings and changes in financial position for the year then ended. Our examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as we considered necessary in the circumstances.

In our opinion, these consolidated financial statements present fairly the financial position of the company as of December 31, 1978 and the results of its operations and the changes in its financial position for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Edmonton, Canada  
January 30, 1979

*Peat, Marwick, Mitchell & Co.*

Chartered Accountants

# CONSOLIDATED TEN-YEAR FINANCIAL SUMMARY

(dollars in millions, except as indicated)

	1978	1977	1976	1975
Operating Revenues				
Natural gas	431.8	318.7	216.5	141.8
Electric	114.7	93.9	78.1	57.9
Other	7.7	2.8	1.3	.7
	554.2	415.4	295.9	200.4
Operating Expenses				
Natural gas supply	315.5	221.3	134.8	70.9
Operating and maintenance	107.2	87.2	72.8	56.5
Taxes — other than income	26.6	21.8	17.0	11.8
Depreciation	23.2	18.8	15.6	13.3
	472.5	349.1	240.2	152.5
	81.7	66.3	55.7	47.9
Allowance for Funds Used During Construction	4.7	2.3	1.3	4.0
Other Income	2.5	1.4	2.3	1.4
	88.9	70.0	59.3	53.3
Interest Expense	22.4	21.4	22.3	19.9
	66.5	48.6	37.0	33.4
Income Taxes	20.0	12.5	8.6	8.7
	46.5	36.1	28.4	24.7
Minority Interests	1.5	.9	.9	.9
	45.0	35.2	27.5	23.8
Net Earnings before Extraordinary Items		(1.6)		2.4
Extraordinary Items — Non-Recurring Gain (Loss)				
Net Earnings	45.0	33.6	27.5	26.2
Preferred Dividend Requirements	9.4	7.5	3.8	5.1
Balance Attributable to Common Shares	35.6	26.1	23.7	21.1
Contribution by Operating Segment*				
Before Extraordinary Items				
Electric	18.7	15.4	12.8	10.7
Natural gas	15.7	11.7	10.8	7.9
Other	1.2	.6	.1	.1
	35.6	27.7	23.7	18.7
Common Shares Outstanding (thousands)				
End of year	18,626	17,122	16,634	14,198
Average for year — fully diluted	18,146	17,312	15,567	14,258
Earnings — Dollars Per Fully Diluted Common Share				
Net earnings before extraordinary items	1.97	1.61	1.55	1.45
Net earnings after extraordinary items	1.97	1.52	1.55	1.61
Common Dividends Paid*				
Dividends per share (dollars)	.9125	.8525	.765	.65
Total dividends paid	16.4	14.4	11.0	7.1
Payout Ratio*				
Dividends paid ÷ earnings available	45.9%	55.2%	46.4%	33.6%
Common Shareholders' Equity Dollars Per Share*				
At year-end — fully diluted	12.22	11.06	10.36	9.41
Rate of Return on Common Shareholders' Equity*				
Before extraordinary items	16.1%	14.6%	14.9%	15.4%
After extraordinary items	16.1%	13.7%	14.9%	17.1%
Stock Market Record of Common Shares* (dollars)				
High	18	15-1/2	14-3/8	9-7/8
Low	14-1/8	12-5/8	9-1/2	7-5/8
Close	16-1/8	15-1/2	14-3/8	9-3/4
Gross Fixed Assets	883.9	780.5	688.6	613.6
Net Fixed Assets	700.1	618.8	542.3	478.6
Total Assets	843.7	744.3	644.3	573.9
Capitalization*				
Long-term debt	234.8	244.3	225.7	181.1
Contributions	59.5	47.5	37.8	27.6
Preferred shares	149.2	129.3	99.3	55.3
Common equity	226.9	187.5	173.9	138.6
Total capitalization	670.4	608.6	536.7	402.6
Capitalization Ratio*				
Long-term debt	35%	40%	42%	45%
Contributions	9%	8%	7%	7%
Preferred shares	22%	21%	19%	14%
Common equity	34%	31%	32%	34%
Times Debt Interest Earned (Pretax)*	3.97	3.26	2.66	2.68

\*Not applicable prior to 1972 corporate reorganization.

Note: Comparative figures for years prior to 1972 have been reclassified to conform with financial presentation following corporate reorganization in 1972.

1974	1973	1972	1971	1970	1969	1968
91.2	82.0	78.9	70.3	62.9	59.2	53.8
46.3	38.3	33.8	30.6	27.7	22.0	18.8
.3	.1					
137.8	120.4	112.7	100.9	90.6	81.2	72.6
40.2	36.0	32.4	27.0	22.6	21.3	19.7
43.6	34.7	33.4	29.1	26.4	23.8	20.6
8.0	6.8	6.5	6.0	5.3	4.8	4.4
12.9	11.0	10.1	9.7	9.4	7.9	7.1
104.7	88.5	82.4	71.8	63.7	57.8	51.8
33.1	31.9	30.3	29.1	26.9	23.4	20.8
1.6	.8	2.2	.8	.2	1.1	.9
1.0	.8	.8	1.3	.7	.6	.9
35.7	33.5	33.3	31.2	27.8	25.1	22.6
17.2	13.7	12.2	9.9	9.1	7.7	6.6
18.5	19.8	21.1	21.3	18.7	17.4	16.0
2.4	4.5	5.0	7.2	6.9	5.7	5.1
16.1	15.3	16.1	14.1	11.8	11.7	10.9
.9	.9	1.0	1.2	1.2	1.2	1.1
15.2	14.4	15.1	12.9	10.6	10.5	9.8
.5		(.1)	.2	.2	2.9	.1
15.7	14.4	15.0	13.1	10.8	13.4	9.9
2.8	2.8	2.7	2.5	2.5	2.5	2.5
12.9	11.6	12.3	10.6	8.3	10.9	7.4

7.2	6.8	9.1
5.2	4.8	3.3

12.4	11.6	12.4
------	------	------

10,075	10,065	10,063	10,056	8,949	8,874	8,874
14,216	14,216	14,216	9,503	8,912	8,874	8,868

1.05	.99	1.05	.91	.80	.81	.74
1.08	.99	1.04	.93	.82	1.03	.76

.59	.55	.52
5.9	5.5	5.2

45.7%	47.4%	42.3%
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8.49	8.04	7.61
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12.4%	12.3%	13.8%
12.7%	12.3%	13.7%

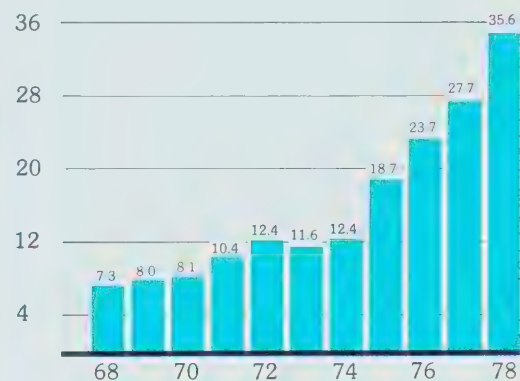
11	13-3/4	14-5/8				
6-1/2	8-5/8	9-1/4				
7-1/4	9-1/4	13-1/2				
538.7	470.3	435.8	397.2	359.4	333.0	308.6
413.5	355.8	330.2	300.0	270.8	252.6	234.6
475.5	391.1	363.1	328.4	306.9	283.9	262.3

194.5	167.5	156.0				
18.1	14.4	12.7				
30.5	30.5	30.5				
115.3	108.9	102.8				
358.4	321.3	302.0				

54%	52%	52%
5%	5%	4%
9%	9%	10%
32%	34%	34%
2.08	2.45	2.32

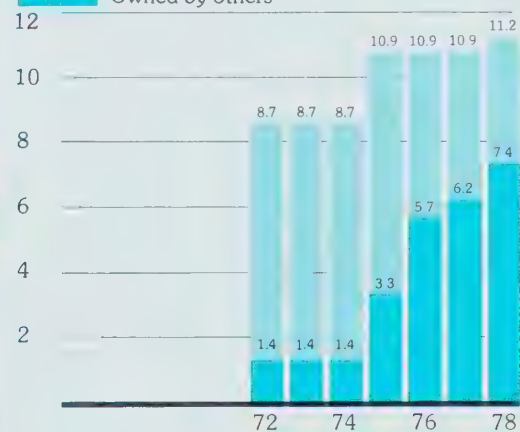
### Balance Attributable to Common Shares

(Excluding extraordinary items)  
(Millions of dollars)



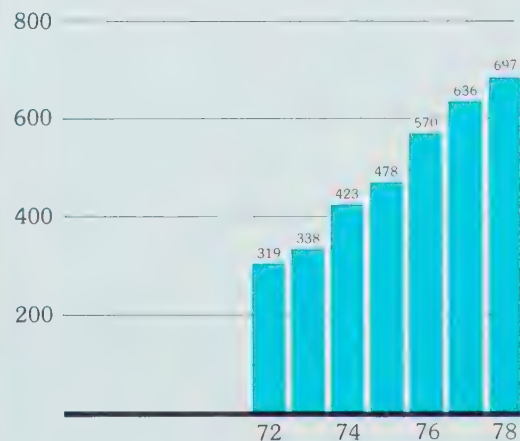
### Common Shares Outstanding (Millions)

Owned by IU International  
Owned by others



### Net Assets (Millions of dollars)

(Total assets less current liabilities)



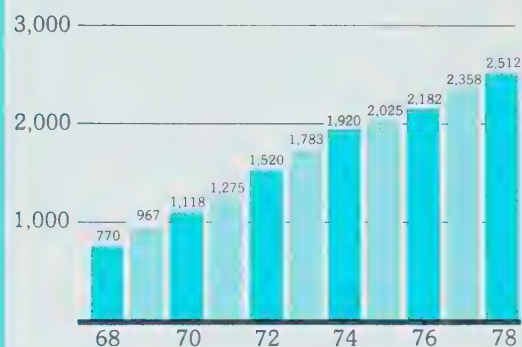
# TEN-YEAR OPERATING SUMMARY

(dollars in millions, except as indicated)

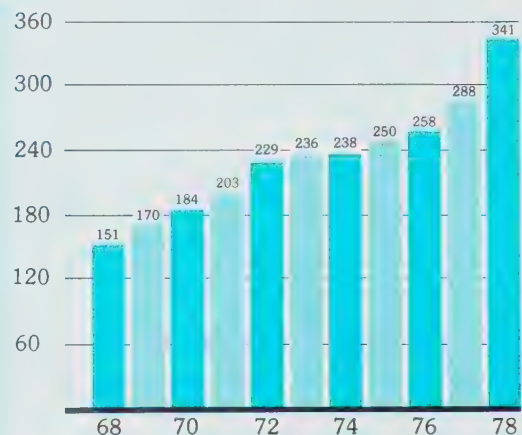
	1978	1977	1976	1975
<b>Electric Operations</b>				
Construction work in progress	31.5	34.4	20.0	14.3
Other	407.2	358.6	332.7	295.0
Gross fixed assets at cost	438.7	393.0	352.7	309.3
Accumulated depreciation	75.4	62.2	53.2	45.7
Net fixed assets	363.3	330.8	299.5	263.6
% growth over prior year	10%	10%	14%	20%
Capital additions in the year	48.1	44.1	45.9	51.1
Sales (millions of kilowatt hours)	2,512	2,358	2,182	2,025
% growth over prior year	7%	8%	8%	5%
Average annual use per residential customer — KWH	7,183	6,879	6,877	6,774
Average annual billing per residential customer (\$)	364	302	273	217
Maximum hourly demand (thousands of kilowatt hours)	520	524	455	445
Generating capacity (thousands of kilowatt hours)	668	671	686	686
Customers at year-end (thousands)	112.5	106.9	99.6	94.0
Number of communities served	386	385	368	365
Power lines (thousands of kilometres)	22.3	20.8	20.1	19.3
<b>Gas Operations</b>				
Gross fixed assets at cost	416.8	370.9	333.9	300.8
Accumulated depreciation	107.6	99.3	93.0	89.3
Net fixed assets	309.2	271.6	240.9	211.5
% growth over prior year	14%	13%	14%	10%
Capital additions in the year	48.2	38.8	39.4	29.5
Sales (billions of cubic feet)	341	288	258	250
% growth over prior year	18%	12%	3%	5%
Average annual use per residential customer — (MCF)	191	180	185	212
Average annual billing per residential customer (\$)	299	241	190	156
Maximum daily demand (thousands of cubic feet)	1,876	1,594	1,430	1,318
Degree days — Edmonton	5,530	5,124	4,891	5,555
— Calgary	5,592	5,289	4,885	5,750
Customers at year-end (thousands)	457.4	428.4	400.5	373.3
Number of communities served	265	260	257	253
Pipelines (thousands of kilometres)	25.0	23.1	21.8	19.5
<b>Other Operations</b>				
Gross fixed assets at cost	28.4	16.6	2.0	1.0
Accumulated depreciation	.8	.3	.2	.1
Net fixed assets	27.6	16.3	1.8	.9
<b>Total Number of Employees</b>	<b>3,592</b>	<b>3,367</b>	<b>3,161</b>	<b>3,133</b>

1974	1973	1972	1971	1970	1969	1968
42.9	11.7	38.9	26.9	4.5	1.3	21.7
217.8	206.5	159.3	148.6	143.0	131.0	96.9
260.7	218.2	198.2	175.5	147.5	132.3	118.6
41.2	36.0	31.8	28.3	24.6	21.1	18.9
219.5	182.2	166.4	147.2	122.9	111.2	99.7
20%	9%	13%	20%	11%	12%	29%
44.8	21.3	24.5	29.1	16.4	15.5	26.1
1,920	1,783	1,520	1,275	1,118	967	770
8%	17%	19%	14%	16%	26%	19%
6,339	6,069	5,961	5,550	5,209	5,127	4,617
184	166	164	156	152	130	122
388	376	342	295	281	245	216
523	512	370	367	367	344	197
88.8	84.6	80.5	77.2	74.2	72.0	70.1
364	365	365	359	355	343	342
18.8	18.1	17.4	16.0	15.6	14.8	13.7

**Electric Sales**  
(Millions of kilowatts)

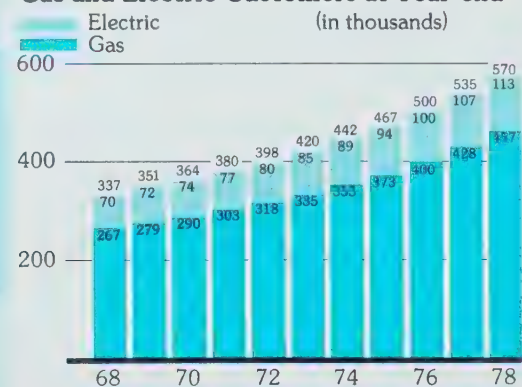


**Gas Sales**  
(Billions of cubic feet)



275.5	251.7	236.9	221.2	211.3	200.1	189.3
83.9	78.6	73.8	68.9	64.0	59.3	55.0
191.6	173.1	163.1	152.3	147.3	140.8	134.3
11%	6%	7%	3%	5%	5%	3%
25.7	17.1	16.5	10.6	11.8	11.5	9.5
238	236	229	203	184	170	151
1%	3%	13%	10%	8%	13%	3%
208	212	230	218	217	223	211
115	113	120	114	108	111	106
1,228	1,109	1,132	1,115	969	894	918
5,492	5,538	6,028	5,737	5,899	5,840	5,612
5,230	5,428	5,973	5,532	5,579	5,760	5,556
353.3	335.5	317.8	303.3	289.5	278.4	266.7
253	253	251	249	240	238	229
16.7	15.8	15.2	14.8	14.1	13.0	11.8

**Gas and Electric Customers at Year-end**  
(in thousands)



1.0						
1.0						
2,933	2,746	2,576	2,298	2,255	2,289	2,272

# CORPORATE INFORMATION

## Board of Directors

**K. A. Biggs**

Senior Vice-President, Finance  
and Treasurer  
Canadian Utilities Limited  
Edmonton, Alberta

**R. F. Calman**

Vice-Chairman  
IU International Corporation  
Philadelphia, Pennsylvania

**\* G. L. Crawford, Q.C.**

Barrister and Solicitor  
McLaws & Company  
Calgary, Alberta

**W. D. H. Gardiner**

Vice-Chairman  
The Royal Bank of Canada  
Toronto, Ontario

**E. W. King**

President  
Canadian Utilities Limited  
Edmonton, Alberta

**P. L. P. Macdonnell, Q.C.**

Barrister and Solicitor  
Milner & Steer  
Edmonton, Alberta

**J. E. Maybin**

Chairman and Chief Executive Officer  
Canadian Utilities Limited  
Toronto, Ontario

**\* D. R. B. McArthur**

Corporate Director  
Edmonton, Alberta

**\* W. S. McGregor**

President  
Numac Oil & Gas Ltd.  
Edmonton, Alberta

**W. S. McLeese**

President  
Trans Canada Freezers Limited  
Toronto, Ontario

**J. M. Seabrook**

Chairman and Chief Executive Officer  
IU International Corporation  
Salem, New Jersey

**R. D. Southern**

President and Chief Executive Officer  
ATCO Industries Ltd.  
Calgary, Alberta

**C. N. W. Woodward**

Chairman and Chief Executive Officer  
Woodward Stores Limited  
Vancouver, British Columbia

\* Member of audit committee

## Honorary Director

**D. K. Yorath**

Edmonton, Alberta

## Canadian Utilities Senior Officers

**J. E. Maybin**

Chairman and Chief Executive Officer

**E. W. King**

President

**K. A. Biggs**

Senior Vice-President, Finance  
and Treasurer

## Staff Executives

**D. R. Brandt**

Vice-President

**A. M. Anderson**

Secretary

**H. N. Bottomley**

Controller

**P. R. Ladouceur**

Assistant Treasurer

## Subsidiary Company Executives

### ALBERTA POWER LIMITED

#### E. W. King

President and Chief Executive Officer

#### W. G. Sterling

Senior Vice-President

#### R. H. Choate

Vice-President

#### D. B. Mitchell

Vice-President, Industrial Relations

#### Keith Provost

Vice-President

### CANADIAN WESTERN NATURAL GAS COMPANY LIMITED and

### NORTHWESTERN UTILITIES LIMITED

#### E. W. King

President and Chief Executive Officer

#### J. H. Pletcher

Senior Vice-President

#### D. B. Mitchell

Vice-President, Industrial Relations

#### D. L. Weiss

Vice-President, Gas Supply

#### A. J. L. Fisher

Vice-President and General Manager

Canadian Western Natural Gas

Company Limited

#### B. M. Dafoe

Vice-President and General Manager

Northwestern Utilities Limited

## Other Subsidiaries Senior Operating Officers

### CU ENGINEERING LIMITED

#### D. M. Murray

General Manager

### CU ETHANE LIMITED

#### D. R. Brandt

President

### CU RESOURCES LIMITED

#### D. L. Weiss

Manager

## Registered Head Office

10040 - 104 Street

Edmonton, Alberta, Canada T5J 2V6

Telephone: (403) 420-7310

Toronto Office:

2314 Commercial Union Tower

Toronto Dominion Centre

Toronto, Ontario, Canada M5K 1H1

Telephone: (416) 869-3868

## Subsidiary Companies

Alberta Power Limited

and subsidiaries:

The Yukon Electrical Company Limited

Yukon Hydro Company Limited

Canadian Western Natural Gas

Company Limited

Northwestern Utilities Limited

and subsidiary:

Northland Utilities (B.C.) Limited

CU Engineering Limited

CU Ethane Limited

CU Resources Limited

## Transfer Agent and Registrar

Common Shares and Preferred Shares:

Montreal Trust Company

Montreal/Toronto/Winnipeg/Regina

Calgary/Edmonton/Vancouver

## Trustee and Registrar

Debentures:

National Trust Company, Limited

Montreal/Toronto/Winnipeg

Calgary/Edmonton/Vancouver

## Stock Exchange Listings

Common Shares:

Toronto, Montreal and Alberta

Stock Exchanges

Preferred Shares:

10¼% second preferred Series A

9.24% second preferred Series B

7.30% second preferred Series C

Toronto and Montreal Stock Exchanges

5% preferred

4¼% Series preferred

6% Series preferred

Toronto Stock Exchange

## Auditors

Peat, Marwick, Mitchell & Co.

2500 Alberta Government

Telephones Tower

10020 - 100th Street

Edmonton, Alberta

## Valuation Day

The following are the Valuation Day prices for Canadian Utilities' common shares and warrants, adjusted for the stock split of September 15, 1972.

Common Shares.....	\$9.31
Warrants.....	\$2.13

## 1978 Common Share Dividends

Record Date	Date Paid	Dollars per Share
Feb. 7/78	Mar. 1/78	.22¼
May 15/78	June 1/78	.22¼
Aug. 10/78	Sept. 1/78	.22¼
Nov. 10/78	Dec. 1/78	.24½
		<hr/>
		.91¼
		<hr/>

## Annual Meeting

The annual meeting of shareholders will be held at 10:00 a.m., April 24, 1979, at the Hotel Macdonald, Edmonton, Alberta.

# CORPORATE STRUCTURE

